

BEFORE THE STATE OF WASHINGTON
ENERGY FACILITY SITE EVALUATION COUNCIL

IN RE APPLICATION NO. 2002-01

EXHIBIT 21.0 (MDT-T)

BP WEST COAST PRODUCTS, LLC

BP CHERRY POINT COGENERATION
PROJECT

APPLICANT'S PREFILED DIRECT TESTIMONY

MICHAEL D. TORPEY

Q. Please state your name and business address.

A. Michael David Torpey, 4519 Grandview Road, Blaine, WA 98230

Q. What is your position at BP?

A. Environmental Manager, Cogeneration Project

EXHIBIT 21.0 (MDT-T)
MICHAEL D. TORPEY
DIRECT TESTIMONY - 1

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1 **Q. What topics will you address in your testimony?**

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3 A. My testimony will address the following issues:

- 4 (1) My background and experience.
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6 (2) My role in connection with the Cogeneration Project.
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8 (3) Project site selection.
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10 (4) Wetland impacts and mitigation.
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12 (5) Air emissions and offsetting emission reductions.
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14 (6) Water use and water quality.
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16 (7) Noise.
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18 (8) Traffic.
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23 **Background**

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25 **Q. Can you describe your background?**

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27 A. I received a B.S. in Chemical Engineering from Washington State University in 1980
28 and started working at the Cherry Point Refinery (owned by ARCO at the time) the
29 same year as a Process Engineer. I worked as a Process Engineer for about seven
30 years and then transferred to the Environmental Group to work as an Environmental
31 Engineer for about five years, between 1987 and 1993. My primary responsibility in
32 the environmental group was air permitting and air compliance. I also worked on
33 water compliance and solid waste for a short period of time. From 1993 to 2000, I
34 supervised various operating and maintenance groups. In 2000, I was assigned to the
35 Cogeneration Project as the Environmental Manager. A copy of my resume is
36 attached as Exhibit 21.1 (MDT-1).
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Role in Cogeneration Project

Q. What is your role in connection with the Cogeneration Project?

A. As the Environmental Manager, I am responsible for coordinating the activities necessary to obtain the environmental permits for the Cogeneration Project.

Q. Can you describe the sorts of things you've been doing in connection with the Cogeneration Project?

A. I have coordinated and overseen the different environmental analyses and reviews necessary for permitting the Cogeneration Project and to meet BP's own environmental goals for the project. In doing so, I hired and have worked closely with environmental consultants who helped us prepare information for the Potential Site Study, the Application for Site Certification ("Application" or "ASC") and the revisions to the Application. I also serve as the primary point of contact between the Project, EFSEC and other environmental regulatory agencies such as the Washington State Department of Ecology and the Corps of Engineers. Because the Cogeneration Project is very closely interconnected with the Refinery, I also coordinate and communicate with Refinery personnel.

Part of my role has also been to communicate with and provide information to people and entities interested in the project. I have participated in numerous meetings with local, state, and federal public officials in the United States and Canada. I have given numerous presentations to public and private groups. And I have discussed the project one-on-one with many members of the community.

1 **Q. Are you the sponsoring witness for the Application (Exhibit 21.2 (MDT-2))?**

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3 A. Yes. I filed the Application with EFSEC on June 10, 2002. In December 2002, we
4 told EFSEC that we had advanced a water reuse agreement to a point that allowed the
5 project to change from an air-cooled plant to a water-cooled plant. These revisions
6 were submitted to EFSEC electronically on April 15, 2003, and in hard copy on April
7 28, 2003. It was my responsibility to supervise the preparation of the Application and
8 its revisions; however, those documents reflect the collaborative efforts of many
9 people, with engineers and environmental consultants providing important input. I
10 can answer questions regarding much of the Application, but, in some instances, I
11 will defer very technical or detailed questions to the experts in that area.
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23 **Project Site Selection**

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25 **Q. Can you describe the proposed project site?**

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27 A. The proposed project site is located in northwest Whatcom County, 6-miles northwest
28 of Ferndale, 7-miles southeast of Blaine, and about 8-miles south of the Canadian
29 border. The site is located immediately adjacent to and at the northeast corner of the
30 BP Cherry Point Refinery. A copy of the project location map, Figure 2.1-1 in the
31 Application, is attached as Exhibit 20.1 to Mark Moore's testimony.
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39 The entire project site is located on BP-owned property. The area is within the
40 Cherry Point Major Industrial Urban Growth Area/Port Industrial Zone as defined by
41 the Whatcom County Comprehensive Plan, issued on May 20, 1997. The project area
42 is zoned Heavy Impact Industrial. A zoning map of the area, Figure 2.1-4 to the
43 Application, is attached to my testimony as Exhibit 21.3 (MDT-3). The site is flat
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1 and can be described as fallow farmland with overgrown pasture grass. A small
2
3 portion of the proposed site contains a stand of hybrid poplar trees that BP planted in
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5 1989 and 1991, with the intention of eventually harvesting them for pulpwood.
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9 **Q. Can you generally describe the configuration of the Cogeneration facility and its**
10 **related infrastructure?**
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13 A. The Cogeneration facility sits on a 33-acre site immediately northeast of the BP
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15 Refinery and south of Grandview Road. The facility includes three gas turbine
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17 generators and three heat recovery steam generators (HRSGs), a steam turbine, an
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19 evaporative water cooler, a water treatment system, and various administrative,
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21 maintenance, and operations buildings. Each HRSG includes catalyst systems for the
22
23 removal of nitrogen dioxide and carbon monoxide and an ammonia injection system
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25 for the nitrogen dioxide catalyst. A high voltage switchyard is situated immediately
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27 adjacent and to the east of the gas turbines and steam generator to collect and
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29 distribute power to the Refinery and the BPA grid. Stormwater is collected on site in
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31 a detention pond and routed to a wetland mitigation area north of Grandview Road.
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33 A natural gas compressor is located near the natural gas metering station inside the
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35 Refinery fenceline to compress the natural gas to the required gas turbine design
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37 pressure. Power is routed off site along a 0.8-mile corridor to an interconnection
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39 point on the west BPA transmission lines between the Custer Substation and the
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41 Alcoa Intalco Aluminum Works plant. Process interconnections between the
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43 Refinery and the Cogeneration Plant, such as steam, water, condensate and natural
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45 gas piping, will be along an elevated pipeway. Several water lines, including the
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47 sanitary sewer line, may be routed underground. A copy of the project site plan,

Figure 2.1-5 to the Application, is attached to Mark Moore's testimony as Exhibit 20.2.

Q. Why did BP select this particular site?

A. Because of the interconnections between the Cogeneration Plant and the Refinery, the Refinery and the Cogeneration facility must be relatively close. Specifically, as a cogeneration facility, the project site needed to be close enough to the Refinery in order to efficiently transport 750° F., 600-psi steam to the Refinery without significant heat loss. In addition, the Cogeneration facility will use existing Refinery infrastructure, such as water supply, sewer connection, condensed steam, wastewater system, potable water, and electrical power.

Initially BP considered locations for the project somewhat south of the current site. However, a wetland survey indicated that the project would have lower wetland impact if it were to be moved north to its current location.

BP considered other sites around the Refinery, but they offered no environmental or economic advantages over the proposed site. For more detail on the evaluation of potential project sites, refer to the ASC, Part III, Appendix H-4, 404(b)(1) Alternatives Analysis.

The current location is also close to the natural gas supply line, the fresh water supply line, and the BPA transmission lines. It is close enough to the Refinery to use existing infrastructure, but also far enough away to keep from interfering with

1 Refinery activities and potential future Refinery modifications, such as clean fuels
2 units. The size the area had to be sufficient large to accommodate the Cogeneration
3 facility equipment.
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9 **Wetland Impact and Mitigations**

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11 **Q. Will construction of the project impact any wetlands?**

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13 A. Yes. A wetland survey indicates the project site and the equipment laydown areas
14 will impact approximately 35-acres of low-grade wetlands.
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19 **Q. Why didn't BP select a site for the project that would not have impacted any**
20 **wetlands?**
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23 A. The entire area around the BP Refinery contains scattered low quality wetlands.
24 Wetland surveys of the general area indicated that moving the project site would
25 impact more wetland area than the chosen site. As explained above, the project site
26 had to be relatively close to the Refinery. Selection of the proposed site minimizes
27 wetland impacts.
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35 In addition, the entire project site is located on BP-owned property. The area is
36 within the Cherry Point Major Industrial Urban Growth Area/Port Industrial Zone as
37 defined by the Whatcom County Comprehensive Plan, issued on May 20, 1997. The
38 project area is zoned Heavy Impact Industrial. As such, Whatcom County has chosen
39 this area as a location for industrial development. Other industries already located
40 within this area include: Alcoa Intalco Aluminum Works, Conoco-Phillips, ChemCo,
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1 Puget Sound Energy Point Whitehorn Generating Station, Tenaska Cogeneration, and
2 PraxAir.
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6 **Q. Can you generally describe BP's proposal to mitigate for wetland impacts?**
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9 A. BP proposes to mitigate the impact to 35 acres of low quality wetlands by restoring
10 and enhancing 110 acres of wetlands on the north side of Grandview Road. The
11 wetland mitigation proposal was designed around three primary objectives: (1)
12 restoring historical hydrology; (2) controlling reed canarygrass; and (3) improving
13 habitat. The mitigation site was chosen because it is in close proximity to the wetland
14 impact area, within the same drainage basin, the area was more than sufficiently large
15 to compensate for the wetland area lost, and it had a high potential for wetland
16 enhancement. It also connects with an existing wetland mitigation area.
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26 First, the wetland proposal restores historical hydrology by collecting and conveying
27 stormwater on the project site to the mitigation area located northwest of the project
28 site. The water would be spread out over a very large area using a long narrow
29 shallow ditch, called a level spreader. The water from the spreader would diffuse
30 slowly through gravel in the lower edge of the ditch berm. The water would generally
31 travel north and west through wetland soils, sand lenses, and vegetation.
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41 The second objective of the wetland mitigation is to control reed canarygrass, a non-
42 native invasive weed. Short-term control would be aggressive elimination through
43 mowing, spraying, plowing, and respraying. Long term, the reed canarygrass would
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1 be controlled with shade from tree and shrubs, and from competition from herbaceous
2 native vegetation.
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6 The third objective is improvement in habitat provided by native trees, shrubs, and
7 herbaceous vegetation. These plants would be installed is such a way to improve
8 habitat diversity, to provide shade to control reed canarygrass, and to improve
9 hydrologic function.
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16 The plan is described in more detail in Appendix H-7 of the Application and in the
17 testimony of Dr. David Every.
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22 **Q. Have you had discussions about this mitigation plan with the U.S. Army Corps**
23 **of Engineers, the Washington Department of Ecology, the Washington**
24 **Department of Fish and Wildlife, and Whatcom County wetlands staff?**
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27 **A.** Yes, we have had numerous discussions with these entities and personnel. Prior to
28 the development of the mitigation proposal, we held meetings with Washington
29 Department of Ecology staff to discuss the design, location, and goals of the wetland
30 mitigation plan. Throughout the development of the wetland mitigation proposal, we
31 have had ongoing meetings with the U.S Army Corps of Engineers (“Corps”), the
32 Washington State Department of Ecology (“WDOE”), the Washington Department of
33 Fish and Wildlife (“WDFW”), and Whatcom County staff to review and discuss the
34 plan. All of the mentioned entities also conducted site visits to the project site and
35 mitigation areas.
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1 **Q. Did you make changes to the mitigation plan in light of those discussions?**

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3 A. Yes. The development of the wetland mitigation plan was an iterative process. We
4 worked closely with the Corps, DOE, and Shapiro, and modified the plan
5 significantly to address their concerns and incorporate their suggestions. The original
6 goal of the mitigation plan was to create wetland from upland to the maximum extent
7 possible and to improve wetland function by improving habitat. A series of meetings
8 were held with the agencies to discuss the initial plan. As a result of these meetings
9 and a thorough review of the proposal, we modified the mitigation plan several times.
10 For example, the agencies asked us to make the restoration of historic hydrology the
11 primary objective of the plan. We agreed upon a plan that would collect stormwater
12 on the project site, route it to the mitigation area, and spread it out over a large area.
13 This change was designed to restore the natural hydrology and effectively slow the
14 rate at which the water reached Terrell Creek. We also agreed to significantly expand
15 the mitigation area and connect it to an existing mitigation area. We believe that the
16 mitigation plan as currently proposed incorporates all of the suggestions offered by
17 these agencies.
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34 **Q. You mentioned finding a way to collect stormwater on the site and route it to the**
35 **wetland mitigation area. Could you briefly describe the stormwater plan for the**
36 **Cogeneration Project?**
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40 A. First, unaffected stormwater from outside the project site will be routed around the
41 site through a series of perimeter ditches. The water will be routed into an existing
42 ditch system alongside the Blaine Road leading to Terrell Creek.
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1 Second, stormwater collected on the project site will be routed to a series of drains
2 and ditches that will route water to a oil/water separator and then to a detention pond
3 before being discharged to the wetland mitigation area. The oil/water separator was
4 added to the stormwater system as a precaution against the potential for an accidental
5 release of hydrocarbons. The separator will provide a place to isolate the
6 hydrocarbon and remove it from the system before the stormwater reached the
7 detention pond. The stormwater being routed to the detention pond will be collected
8 from areas with a very low potential for contamination, such as roof tops, parking
9 lots, and streets. The stormwater detention pond has been designed according to the
10 Washington State Department of Ecology guidelines to control both the quality and
11 quantity of the stormwater collected and routed to the mitigation area.
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25 Third, stormwater from secondary containment areas will be inspected for
26 contamination. If determined to be clean, this stormwater will be discharged to the
27 stormwater system. If the stormwater is potentially contaminated, it will be sent with
28 the Cogeneration facility's industrial wastewater to the Refinery's wastewater
29 treatment system. It should be noted that, because the Cogeneration Project does not
30 have an onsite backup fuel source, the secondary containment areas and related
31 storage tanks are small.
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41 **Q. What's the status of the Corps 404 Permit process regarding this project?**

42 A. The 404 permit application was filed with the U.S. Army Corps of Engineers on April
43 14, 2003 with the submission of the following documents: The Joint Aquatic
44 Resources Permit Application, the Certification of Consistency with the Washington
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1 State Coastal Zone Management Program for Federally Licensed or Permitted
2 Activities, the Revised Compensatory Project Mitigation Plan (URS 2003), the
3 Revised Project Compensatory Mitigation Areas Wetland Delineation Report (URS
4 2003), the Wetland Delineation Report BP Cherry Point Cogeneration Project
5 (Golder Associates, 2003), the Technical Report on Wetland Functions and Values
6 Assessment BP Cherry Point Cogeneration Project (Golder Associates, 2003), the
7 Siting and Alternatives Analysis BP Cherry Point Cogeneration Project (Golder
8 Associates, 2003), and the Biological Evaluation – BP Cherry Point Cogeneration
9 Project. The Corps issued a public notice for the 404 permit on July 22, 2003 and the
10 comment period will expire October 27, 2003.
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23 **Q. Will BP present testimony of other witnesses that can address wetland issues in**
24 **greater detail?**

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27 A. Yes. Dr. David Every of URS Corporation prepared the wetland mitigation plan and
28 he will provide testimony regarding wetland issues.
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33 **Air Emissions & Offsetting Reductions**

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35 **Q. There has been a lot of talk about the BP Cogeneration Project resulting in a net**
36 **decrease in air emissions from Cherry Point. Can you explain how this would**
37 **occur?**
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41 A. Absolutely. This will occur because of offsetting air emission reductions at the
42 Refinery that are associated with the cogeneration aspect of the project. I'll explain.
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1 The Refinery currently operates utility boilers to produce steam for the Refinery.
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3 Steam is used throughout the Refinery to heat oil and move oil. These boilers are
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5 critical to the operation of the Refinery. If too much steam is produced, then the
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7 excess steam is vented to the atmosphere and energy is wasted. If too little steam is
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9 produced, then Refinery process equipment, such as steam turbines, does not operate
10
11 properly. This steam balance is critical to the safe and reliable operation of the
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13 Refinery.
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16 The Cogeneration Plant will export steam to the Refinery to be used in Refinery
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18 processes. Steam from the Cogeneration facility will enable the Refinery to reduce or
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20 eliminate the production of steam in its utility boilers. The air emissions associated
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22 with the production of steam in the utility boilers will be reduced or eliminated.
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26 **Q. How did you calculate the amount of emission reductions from these offsets?**
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28 **A.** Very simply, we subtracted the amount of Refinery emission reductions from the
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30 expected Cogeneration facility emissions, and the total resulting difference was a net
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32 decrease in emissions of criteria pollutants of 140 tons/year. The breakdown by
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34 pollutant is included in Table 3.2-17 from § 3.2 of the Application reprinted here.
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Table 3.2-17

**Expected Annual Emissions With Refinery Emission Reductions
(RENUMBERED/REVISED, APRIL 2003)**

| | NO _x | CO | VOC | PM ₁₀ | SO ₂ | Total |
|--|-----------------|-----|-----|------------------|-----------------|-------|
| Expected Emissions | 181 | 81 | 28 | 94 | 50 | 433 |
| Refinery Emission Reductions | -499 | -54 | -3 | -10 | -7 | -573 |
| Total Change in Emissions | -318 | 27 | 25 | 84 | 43 | -140 |
| Totals may not equal sum of individual components due to rounding. | | | | | | |

Q. How did you determine the expected annual Cogeneration emissions for this calculation?

A. The expected annual emissions from the Cogeneration Project are provided in section 3.2 of the Application. They are calculated based on a number of factors: The expected long term average operating scenario, the expected average stack emissions, and an adjustment in particulate emission based on the inherent error in the EPA reference method test.

The expected operating scenario is based on a 6-year cycle of operations taking into account market conditions and required maintenance. This same operating scenario was also used to perform the economic evaluation of the project.

Stack emissions of NO_x and CO are expected to be slightly less than the absolute maximum emission allowed by the permit. Based on my operating experience with other emission control equipment, we believe it is reasonable to expect that the average NO_x emission rates would be at or below 90% of the absolute maximum

1 short term limit allowed by the permit and the CO emission rates would be at or
2 below 80% of the absolute maximum short term limit allowed by the permit.
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6 **Q. You also mentioned “an adjustment in particulate emission based on the**
7 **inherent error in the EPA reference method test.” Can you explain this**
8 **adjustment?**
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10 **A.** Yes. In summary, the EPA reference method exaggerates the particulate due to the
11 conversion or sulfur dioxide to sulfate in the test equipment. To be accurate, the
12 particulate emissions need to be adjusted to account for this overstatement.
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20 Before I explain how this occurs, let me give a brief history of how we learned of this
21 error. Particulate emission estimates provided by equipment manufacturers are
22 typically higher than we would expect for natural gas combustion, but they are
23 generally low enough to meet all the applicable air quality standards so most facilities
24 do not look at the numbers in detail. During public meetings regarding the
25 Cogeneration Project, we heard a number of specific comments about particulate
26 matter emissions and we felt that this was something that deserved more attention. In
27 our search for information, we found extensive research by GE Energy and
28 Environmental Research Corporation (Wein and England, 2002) that not only
29 identified the type of particulate being captured in the EPA test, but also showed that
30 the particulate numbers were being overstated.
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45 The overstatement relates to measurement of sulfur dioxide (SO₂) which is present as
46 a gas in the stack. There are two reasons for the overstatement. First, under the EPA
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1 test method, SO2 is inadvertently collected and measured as a particulate with the
2 particulate sampling equipment. More specifically, SO2 present in the stack gas is
3 collected in the back half (condensable section) of the particulate sampling
4 equipment. The SO2 and oxygen dissolves in a “bubbler” filled with water where the
5 SO2 is slowly oxidized to sulfate and ultimately measured as a particulate.
6
7 Therefore, because sulfate is heavier than SO2, the SO2 is exaggerated when it is
8 measured as sulfate. Second, and even more significantly, the SO2 in the stack gas is
9 measured independently in a different test. The EPA method for this test includes
10 both the SO2 gas and sulfate measurements in its results. The SO2 is therefore
11 double counted and results in an exaggeration of particulate matter emissions.
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23 **Q. How did you calculate the second part of your emissions offset equation – the**
24 **amount of Refinery emission reductions?**

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26 A. We calculated the amount of Refinery emissions reductions based on the reduction or
27 elimination of fuel burned in Refinery utility boilers and two Refinery heaters. When
28 the Cogeneration Plant supplies steam to the Refinery, the energy in this steam will
29 allow the Refinery to reduce the production of steam from utility boilers #1, #2, #3,
30 and #4 to maintain the steam balance. In addition, Refinery fuel gas is currently used
31 in two heaters, the Hydrocracker Second Stage Fractionation Reboiler and the
32 Naphtha Hydrodesulfurization Stripper Reboiler, to heat oil being routed into
33 distillation columns. These towers would be modified to incorporate steam heat
34 exchangers. The steam from the Cogeneration Plant would be used as the heating
35 medium for these exchangers, which would allow the Refinery heaters to burn less
36 fuel and produce fewer air emissions as a result.
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The Refinery emission reductions that come from reducing or eliminating the production of steam in utility boilers #1, #2, #3, and #4, the Hydrocracker Second Stage Fractionation Reboiler, and the Naphtha HDS Stripper Reboiler are set out in the following table. The emission reductions are based on the average annual expected emissions from these utility boilers and heaters prior to the Cogeneration project start up.

| | Current Steam Demand | Future Additional Steam Demand | Refinery Heaters | Total |
|---|----------------------|--------------------------------|------------------|-------|
| NOx | 278 | 186 | 35 | 499 |
| CO | 23 | 19 | 12 | 54 |
| VOC | 1 | 1 | 1 | 3 |
| PM10 | 5 | 4 | 2 | 10 |
| SO2 | 4 | 3 | 1 | 7 |
| Refinery Emission Reductions | 310 | 213 | 51 | 573 |
| Based on average annual expected emissions. | | | | |

Q. Some people have asked whether these offsetting emission reductions will be enforceable or whether there is any guarantee that they will be implemented at the Refinery. What is your response to that?

A. Although the PSD permit cannot require changes at the Refinery, a primary purpose of the Cogeneration Project is to reduce the cost of steam and power to the Refinery. BP will remove Boilers #1, #2, and #3 from service after the Cogeneration Project

1 starts operations and is proven sufficiently reliable. Even though the older boilers
2 (#1, #2, and #3) would not be available, there would be sufficient steam production
3 capacity available in the Refinery to operate the Refinery if the Cogeneration plant
4 were completely shutdown.
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10 **Q. The Draft Environmental Impact Statement (DEIS) issued by EFSEC suggests**
11 **that requiring removal of the Refinery's three utility boilers within six months of**
12 **beginning Cogeneration facility operation could allow regulatory agencies to**
13 **more fully take into account Refinery emission reductions in the permitting and**
14 **environmental review processes. Is BP willing to agree to such a condition?**
15

16 **A.** BP can remove the Refinery's #1, #2 and #3 boilers once reliable operation of the
17 Cogeneration facility is ensured, and is willing to agree that they will be removed
18 within six months of the facility entering commercial operation (distinguished from
19 startup operation).
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30 **Q. Some people have suggested that these offsets won't occur, because when the**
31 **price of electricity is high, BP might operate both its Refinery boilers and the**
32 **Cogeneration Project to maximize electricity production. What is your**
33 **response?**
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38 **A.** Put simply, the engineering design of the facility makes it impossible to maximize
39 electricity production by not providing steam to the Refinery. Because the plant is
40 designed as a cogeneration facility, it is designed to operate at peak efficiency in
41 cogeneration mode, which is when it is exporting steam to the Refinery. The
42 maximum output of the plant requires steam export to the Refinery. The steam
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1 turbine is designed with an extraction point in the middle of the turbine to send 600-
2 psi steam to the Refinery. The turbine contains two halves, a front half and a back
3 half. The front half of the turbine is designed to feed all the steam produced by the
4 HRSGs. The back half of the turbine is designed to feed the steam from the front half
5 of the turbine minus the steam being sent to the Refinery. When less steam is sent to
6 the Refinery, there is more steam available from the front half of the turbine than will
7 fit in the back half of the turbine and the excess steam would have to be sent directly
8 to the condenser where it would be condensed and sent back the HRSGs as water.
9 This would waste the steam and produce no electricity. On the Refinery side, since it
10 would be receiving steam during maximum operation of the Cogeneration facility,
11 there would be no reason to operate its boilers. The Refinery must maintain a steam
12 balance; in other words, it can't use more steam than it needs. Excess steam is vented
13 to the atmosphere. As a result, steam production in the Refinery will always be
14 reduced or eliminated when the Cogeneration Facility supplies steam to the Refinery.
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31 **Q. Can you generally describe the emission control technology that will be used on**
32 **the project?**
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34 A. Best Available Control Technology (BACT) would be used to control the emissions
35 of nitrogen dioxide and carbon monoxide from the Cogeneration Plant. BACT for
36 nitrogen dioxide was determined to be Dry Low NOx (DLN) Burners and Selective
37 Catalytic Reduction (SCR). The DLN burners are designed to produce less nitrogen
38 dioxide than standard burners, which is done by reducing the peak flame temperature.
39 The amount of nitrogen dioxide created during combustion is a function of time and
40 temperature. DNL burners mix the air in such a way that the peak flame temperature
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1 is reduced and less NOx is produced during combustion. The second control
2 technology for nitrogen dioxide is SCR, which is a catalyst system placed within the
3 HRSG and the even distribution of ammonia across the catalyst surface. The
4 presence of ammonia and catalyst in the HRSG converts most of the nitrogen dioxide
5 in the flue gas to nitrogen prior to leaving the stack. Emissions of carbon monoxide
6 from the HRSG stacks would be controlled with good combustion control and a
7 catalytic oxidation system. Again, the burners are designed in such a way to achieve
8 nearly complete combustion. The second level of control involves the presence of the
9 oxidation catalyst placed within the HRSG and oxygen in the flue gas. This catalyst
10 system converts most of the carbon monoxide to carbon dioxide before being released
11 from the stack. The oxidation catalyst also converts a variety of organic constituents
12 in the flue gas to carbon dioxide.
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27 The cooling tower would be equipped with drift control to achieve a 0.001% drift
28 rate. Cooling tower drift is caused by the air flowing through the cooling tower at a
29 sufficiently high velocity to carry small water droplets out of the tower. A drift
30 control system consists of a stationary device at the top of the cooling tower that
31 minimizes the flow of droplets leaving the tower. The air flows through the cooling
32 tower at velocity high enough to carry small droplets of water through the tower. As
33 the air enters the top of the tower it passes through a series of plates that cause the air
34 to change directions. As a gas, the air changes directions at these plates very easily.
35 The water droplets being carried by the air, being heavier, turn more slowly and
36 instead of going around the plates, they tend to impact these plates and form larger
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1 droplets. These droplets become large enough that the air is no longer able to carry
2 them and they to drop back into the tower.
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6 **Q. What are the emissions rates for criteria pollutants associated with the**
7 **Cogeneration facility?**
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9

10 A. Hourly emission rates are dependent on the gas turbine load, duct firing rate, and
11 ambient temperature. Case 6A described in the Application represents the highest
12 hourly emission rates for the Cogeneration facility (from Application, § 3.2, Table
13 3.2-12) and therefore presents a worst case picture here. However, in all likelihood
14 the facility would operate in this mode a very small percentage of the time, which
15 would be dependent on the steam needs of the Refinery. Under the highest operating
16 scenario (which assumes 5° F, 100 % turbine load, and 105 mmbtu/hr duct firing),
17 emission rates for criteria pollutants from the facility are: NOx 18.7 lbs/hr; CO 22.8
18 lbs/hr (short-term average); VOC 3.0 lbs/hr; PM10 20.6 lbs/hr; and SO2 8.8 lbs/hr
19 (short-term average). In addition, the Cooling Tower will emit PM10 at a rate of 1.63
20 lbs/hr. Testing (and use in an emergency) of the Emergency Diesel Generator and the
21 Fire Water Pump have associated periodic emissions as reflected in the Application.
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36 **Q. What are the maximum potential annual emissions for these criteria pollutants**
37 **associated with the Cogeneration facility?**
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40 A. The maximum annual potential emissions for the turbines and auxiliary equipment
41 are set out in the Application § 3.2, Table 3.2-15. They are: NOx 233.3 tons/yr; CO
42 157.7 tons/yr; VOC 42.3 tons/yr; PM10 261.6 tons/yr; and SO2 51.0 tons/yr. These
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1 emission estimates include the emergency diesel generator, fire water pump, and
2 cooling tower.
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6 **Q. Do you expect the actual emissions to be below those "maximum potential to**
7 **emit" values?**
8

9
10 **A.** Yes. PSD permitting is based on the maximum potential to emit. The PSD air
11 quality modeling is therefore performed on the maximum potential emission rates.
12 As a result, if modeling demonstrates that the plant will meet all air quality standards
13 at all times of the year while operating at the highest potential emission rates, then
14 logically the plant would meet all air quality standards for all modes of operation at
15 any time of the year. The advantage in this approach is that it allows the plant to
16 operate at any level of operation and at any time of year with the knowledge that all
17 air quality standards are met.
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28 We do not expect to continuously operate the plant at the level that was used for the
29 PSD air quality modeling -- the level that produces maximum potential emissions.
30 Rather, expected operating conditions of the plant, taking into account required
31 maintenance and power price fluctuations are shown in the following table.
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| Operating Scenario | Description | Level of Operation |
|--------------------|------------------------------------|--------------------|
| Case 1AB | 100% Load with no duct firing | 55% |
| Case 2B | 100% Load with minimal duct firing | 39% |
| Forced Outage | Unplanned Shutdown | 2% |
| Economic Dispatch | Economic Shutdown | 1% |

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| | | |
| Planned Outage | Maintenance | 3% |

Expected operating conditions will therefore result in actual emissions much lower than demonstrated in the PSD air quality modeling. Expected annual emissions are reflected in Table 3.2-16, § 3.2 of the Application. They are: NO_x 181.1 tons/yr; CO 81.2 tons/yr; VOC 27.5 tons/yr; PM₁₀ 242.4 tons/yr; and SO₂ 49.6 tons/yr. I have included a table below that compares the actual expected annual emissions with the maximum potential annual emissions used for the PSD modeling.

Comparison of Expected Annual Emissions to Maximum Potential Annual Emissions

| | Annual Emissions (tons/yr) ¹ | | | | |
|--|---|-------|------|-------------------------|-----------------|
| | NO _x | CO | VOC | PM ₁₀ | SO ₂ |
| Expected Annual Emissions (Criteria Pollutants) | 181.1 | 81.2 | 27.5 | 242.4/93.9 ² | 49.6 |
| Maximum Potential Annual Emissions (Criteria Pollutants) | 233.3 | 157.7 | 42.3 | 261.6 | 51.0 |
| ¹ Emissions numbers include auxiliary equipment (emergency generator, firewater pump and cooling tower). ² 93.9 tons/yr is the PM ₁₀ emission level adjusted down from the overstatement in the source test method. Approximately 60% of the PM ₁₀ emissions are subtracted due to source test exaggerations of sulfates and the inclusion of compounds associated with background ambient air. | | | | | |

1 **Q. Can you explain why you expect emissions to be below the permitted amount?**

2
3 A. Certainly. There are several reasons. (1) As mentioned above, the plant is not
4 expected to operate at peak load continuously. Expected annual emissions are based
5 on how we would expect to operate the facility over the course of several years taking
6 into account downtime for required maintenance and the variation in plant production
7 due to power price fluctuations. (2) Also, we expect particulate to be much lower
8 than the turbine emissions estimates provided by the manufacturer. Based on the GE
9 research discussed above, the particulate matter emission estimates are overstated due
10 to inherent errors in the EPA test method. (3) The stack emissions of NOx and CO
11 are expected to be controlled to a concentration that would be less than their absolute
12 permit limit to take into account operating fluctuations. We estimated the NOx
13 emissions based on an average of 90% of the absolute permit limit values and CO
14 emissions based on 80% of the absolute limit.
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29 **Q. BP has stated that it also expects an overall reduction in particulate as a result of**
30 **this project. Can you explain how that will occur?**

31
32 A. Very simply, because the Refinery emission reductions result in a very large decrease
33 in NOx, a precursor to secondary particulate, we expect a substantial reduction in the
34 formation secondary particulate. Brian Phillips provides a detailed explanation of
35 this reduction in his testimony.
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43 **Q. Will BP present testimony from another witness who can address air quality**
44 **issues in greater detail?**
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1 A. Yes. Brian Phillips performed the air quality modeling and he will testify regarding
2 these issues.
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7 **Water Use and Water Quality**
8

9 **Q. How much water will the Cogeneration Project use?**

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11 A. The amount of water needed by the Cogeneration Project varies with ambient
12 temperature and operating conditions of the plant. On average, the Cogeneration
13 plant requires 2244 to 2316 gpm of water. Potable water consumption is estimated to
14 be 1-5 gpm.
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21 **Q. Where will this water come from?**

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23 A. Industrial water for the Cogeneration Plant would be purchased from the Public
24 Utility District of Whatcom County ("PUD"). An innovative agreement between the
25 BP, Alcoa, and the PUD has been developed to supply water to the project and at the
26 same time decrease water withdrawn from the Nooksack River. Under this
27 agreement, the PUD would build and operate a system to reuse the 2780 gpm of
28 industrial water currently allocated to Alcoa for cooling purposes. The industrial
29 water for the Cogeneration facility will come from this once-through, non-contact,
30 cooling water from Alcoa, and will be pumped to the Cogeneration Project via an
31 existing 24-inch water supply line between Alcoa and the Refinery.
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43 Since the amount of reuse water available from Alcoa's allocation is more than the
44 2,244 to 2,316 gpm of water that the Cogeneration Project needs on average, the extra
45 water would be available for other industrial users, including the Refinery. I have
46
47

1 attached to my testimony three diagrams that lay out in simplified form the water
2 reuse flow, see Exhibit 21.4 (MDT-4).
3
4
5

6 **Q. How will this affect the amount of water in the Nooksack River?**
7

8 **A.** As I said, because the amount of reuse water is more than the Cogeneration Project
9 requires, the extra water is available for other industrial users, including the Refinery.
10 This extra water will therefore not need to be drawn from the Nooksack River to
11 serve other users. In other words, since 2780 gpm of water would be made available
12 from Alcoa, but the Cogeneration project only needs between 2244 and 2316 gpm,
13 there will be water withdrawal savings from the Nooksack River of between 536 and
14 464 gpm.
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23 **Q. You've said you'll reuse cooling water from the Alcoa facility. What would**
24 **happen if the Alcoa facility were permanently shut down?**
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26 **A.** The shutdown of Alcoa, temporarily or permanently, would not have any adverse
27 water use consequence. In such an event, the Cogeneration water would be
28 purchased directly from the PUD. As this water was previously diverted for use by
29 Alcoa, it would not increase water withdrawals from the Nooksack River. Moreover,
30 because the volume of water needed by the Cogeneration is less than the 2780 gpm of
31 cooling water used by Alcoa, the amount of water withdrawn from the Nooksack
32 would decrease. In fact, as explained above, the amount of water withdrawn will
33 decrease with the Cogeneration facility in operation whether or not Alcoa is
34 shutdown.
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1 **Q. What wastewater is generated by the Cogeneration Project?**

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3 A. There are three primary wastewater streams generated by the Cogeneration project:
4 (1) Wastewater from water treatment; (2) wastewater from process areas; and (3)
5 cooling tower blowdown. In total, the average wastewater flow amounts to 190 gpm.
6
7 Wastewater from water treatment contains minerals that are removed from the water
8 in preparing it for boiler feed water. The process is similar to water softening, but
9 produces a much higher purity water. The water from the process areas would be
10 primarily rain water, but it is captured in a process area where it could be
11 contaminated with lubricating oil. The cooling tower blowdown contains water with
12 minerals that are concentrated due to water being evaporated in the cooling tower.
13
14 The concentration of these minerals is dependent on the amount of minerals present
15 in the cooling tower feed water and the number of cooling tower cycles. This stream
16 may also contain low concentrations of cooling tower chemicals, such as a biocide to
17 inhibit algae growth and a dispersant to minimize condenser deposits. Table 3.3-3 in
18 § 3.3 of the Application provides detail regarding the facility's wastewater.
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32 **Q. Where will the wastewater from the facility go?**

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34 A. The Cogeneration Facility wastewater will be routed to an equalization tank in the
35 Cogeneration Facility and then pumped to the Refinery's Wastewater Treatment
36 System. After treatment in the Refinery's treatment system, the wastewater will be
37 discharged with Refinery wastewater through the Refinery's outflow in the Georgia
38 Strait.
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1 **Q. Will the project change the quantity or quality of water being discharged from**
2 **the Refinery treatment system?**
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5 A. The 190 gpm of Cogeneration wastewater would increase the average amount
6
7 wastewater treated by the Refinery Wastewater treatment system by about 8%. The
8
9 Cogeneration project wastewater would otherwise cause only very small increases in
10
11 certain contaminants, and the combined wastewater discharge would remain within
12
13 the limits of the Refinery's existing NPDES permit.
14

15
16 **Q. Will BP present testimony from another witnesses who can address water issues**
17 **in greater detail?**
18

19
20 A. Yes. Bill Martin will testify regarding wastewater treatment. In addition, Michael
21
22 Kyte will testify regarding water quality and quantity impacts on marine
23
24 environments and aquatic life.
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28
29 **Noise**
30

31 **Q. Has BP analyzed sound emissions from the project?**
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33 A. Yes. There have been three separate noise monitoring surveys conducted during the
34
35 application process. In May and June 2001, Golder Associates monitored fifteen
36
37 noise receptor locations around the proposed site for background noise and to
38
39 determine any noise impacts from the project. The results are reported in Appendix
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41 K of the Application.
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45 After the project layout was revised, in April 2003, Hessler Associates, Inc.,
46
47 performed additional monitoring at four locations that were the nearest sensitive

1 receptors (residences, churches, etc.) to the project. The monitoring results and
2 results of subsequent modeling of future noise emissions from the plant are included
3 in the Application in a memorandum dated April 16, 2003, attached to Appendix K.
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8 In addition, during the development of the application, we received comments from
9 residents of Birch Bay with concerns about potential noise increases. We met with
10 Sharon Roy (Whatcom County Councilperson), Jim Thompson (noise engineer with
11 Whatcom County Planning and Development Services), and David Grant (Whatcom
12 County assistant prosecuting attorney) to discuss local noise concerns and to develop
13 a plan for additional noise monitoring. Four additional monitoring locations were
14 chosen in coordination with these County representatives: (1) 8026 Birch Bay Drive;
15 (2) 4825 Alderson Road; (3) Arnie Road (1300 ft east of Blaine Road); and (4)
16 Jackson Road (across from the Puget Power gas metering station). The monitoring
17 data was again used to model expected sound levels with the plant in operation.
18 These results are reported in a memorandum attached as Exhibit 24.5 to the testimony
19 of David Hessler.
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35 **Q. Are the sound emissions within regulatory limits?**

36 A. Yes. The modeling showed that the plant would be in compliance with state
37 regulatory requirements and would not likely result in a perceptible noise increase
38 during steady-state operation.
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45 **Q. Does the project proposal contain any design features to mitigate noise impacts?**
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1 A. Yes, the following noise attenuation features have been incorporated into the current
2 design.
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- 4 • Silencers in the exhaust stacks
- 5 • Silencers in the air intake
- 6 • Acoustical insulation on piping where appropriate
- 7 • Silencers on vents
- 8 • Enclosures on BFW pumps
- 9 • Steam turbine enclosure
- 10 • Gas turbine enclosure
- 11 • Different site arrangement

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24 **Q. Is BP working with a noise consultant to address sound emissions during the**
25 **project design?**
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27
28 A. Yes. BP has and will continue to work with noise consultants throughout the project
29 design to ensure that the project meets noise regulations and avoids significant noise
30 increases.
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36 **Q. Will BP be presenting testimony from another witness that can address noise**
37 **issues in greater detail?**
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39
40 A. Yes. David Hessler has performed ambient monitoring and has modeled the project's
41 effect on noise. He will testify regarding these issues.
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Traffic

Q. How many workers will be employed by the Cogeneration Project?

A. During construction, the workforce follows a bell shaped curve with low work force numbers at the beginning and end of the construction period and a peak in the work force numbers in the middle. The construction workforce peaks at about 700 workers mid-way through the 25-month construction period. The average workforce is about 372 people over the 25-month construction period. Once in operation, the Cogeneration Project will employ about 30 full-time workers.

Q. Will these additional employees adversely affect traffic in the area of the project?

A. No, we do not expect any permanent adverse impacts to traffic. The number of employees during operation is not high enough to adversely impact traffic. During construction, any traffic impacts will be temporary, occurring only during the construction peak. Such temporary traffic increases have been successfully managed for the Refinery in the past. We have had meetings and discussions with several representatives of Washington State Department of Transportation (WSDOT), including Roland Storme and Lee Conrad of the regional office in Burlington, and Allen Harger, based at headquarters. We are optimistic of reaching an agreement with WSDOT on how best to address the temporary traffic impacts.

END OF TESTIMONY